

White Paper: Coal Mine Methane in Today's Natural Gas Market

**Prepared for
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I. INTRODUCTION

The natural gas market has undergone revolutionary changes in the last decade. It has been transformed from a utility service to a commodity market. This is largely a consequence of the Federal Energy Regulatory Commission's (FERC's) Order 636, passed in 1992, which restructured the natural gas pipeline industry. In the past, government regulations prescribed everything from the price of natural gas to who could buy, sell and transport it and under what conditions. Today the natural gas industry has evolved to a market-based industry where *normal commercial relationships* largely define industry operations. There are far fewer regulatory barriers to industry operations, making it much easier for the marketing of coal mine methane.

Marketing coal mine methane can be profitable. Some operators of gassy coal mines have certain advantages when competing in the natural gas industry:

- In most cases, drilling and gathering costs for methane removal from mines can be considered a "sunk" cost for purposes of marketing the methane, since these wells would have been necessary for mining operations. The costs of marketing methane, therefore, can be lower than comparable conventional gas production.
- Many gassy mines are located east of the Mississippi, near major gas consuming regions. These mines would compete with Appalachian gas supplies and as such can receive higher netback prices for mine owners than those received by natural gas producers in the Southwest or Canada.
- Many gassy mines are also located downstream of natural gas pipeline bottlenecks in Texas and Louisiana, giving them an edge in making cold-weather winter deliveries, when most of the interstate pipelines are running at capacity.
- Abandoned coal mines may be especially suitable for gas storage. Storage with rapid withdrawal capability is a high value service in the gas industry.

In order to take advantage of these opportunities, however, coal mine operators must make a long-term commitment to get their gas to market. This includes the capital costs needed to produce the gas and move it to major pipeline connections, as well as the development of commercial relationships with marketers, transporters and customers.

This paper introduces the reader to today's natural gas market and explains under what conditions the sale of coal mine methane in the natural gas market is possible. Ultimately, whether a coal mine operator can profitably sell the methane from a mine will be determined by the particulars of the situation and market conditions.

This paper is organized in three sections. The first section provides an overview of the natural gas industry, with emphasis on the significance of FERC Order 636. It outlines the general market structure, identifies the key players in the industry and describes the market factors that determine gas prices in the post-Order 636 environment. This section also addresses how changes in the industry affect the marketing of natural gas. The second section focuses on the details of marketing natural gas through a discussion of the structure of typical gas sales

contracts and transportation agreements. The final section focuses specifically on the marketing of coal mine methane.

This paper assumes that coal mine methane producers are similar to any small to medium sized gas producer in that there are no inherent liabilities or advantages associated with coal mine methane that would not also be faced by any gas producer similarly located. Natural gas is a commodity, and coal mine methane sold as natural gas is commercially indistinguishable from any other source of gas.

II. OVERVIEW OF THE NATURAL GAS INDUSTRY TODAY

A. The Industry Before FERC Order 636

The modern natural gas industry began with the construction of large diameter pipelines made possible by advances in metallurgy in the late 1920s. Prior to this, natural gas transmission was a local affair, and was regulated, if at all, by state utility commissions. Federal regulation followed the construction of long distance interstate pipelines with the Natural Gas Act in 1938. The Federal Power Commission, predecessor to FERC, was given the responsibility of regulating the construction of interstate pipelines, interstate pipeline transportation tariffs, and later with the Supreme Court decision in *Phillips Petroleum Co. v. State of Wisconsin* in 1952, the wellhead price of gas itself.

Interstate pipelines historically served as the wholesale merchants of gas, buying gas at the wellhead from individual producers, aggregating supplies, transporting gas to market, and reselling it to local distribution companies (LDCs). Pipelines owned the gas they sold; they were not in the business of transporting gas for others, and as such, the infrastructure they developed served the merchant function. The interstate pipelines operated large gathering networks drawing gas from thousands of wells. These fed into processing plants where gas was stripped of hydrocarbons, water and liquids, and then to the long distance mainline transmission systems that connected with the LDCs. Pipelines operated storage facilities near markets to supplement winter gas supply and help balance pipeline flows.

As the principal natural gas merchants, pipelines exercised major control over the natural gas industry. They alone bought gas for resale in interstate commerce.¹ Pipelines purchased gas under long term (20 year) contracts and resold the gas under long term “service agreements” to LDCs as part of a “bundled service” that included in one price the cost of gas and all the delivery services. (In rare instances pipelines sold directly to industrial plants. Transportation services--as opposed to sales services--were even more rare.) Pipeline rates were based on cost-of-service concepts and pipelines’ profits were based on their net investment in capital equipment (rate base).

This constituted a highly restrictive system that limited market entrants and, with regulated prices for natural gas, led to widespread shortages of gas in interstate markets after the 1973 oil crisis.² Congress responded with the Natural Gas Policy Act (NGPA) in 1978, which raised interstate prices for new gas production. These higher-priced supplies led to an oversupply of natural gas (known as the “natural gas bubble”). Downstream pressure to open up the system eventually led to partial gas price deregulation in 1985 and subsequently to full deregulation in 1989.³

¹ In the terminology of the FERC, the initial purchase of gas from the producer by the pipeline was the “first sale,” with the “resale” being the sale of this gas to the LDC.

² The shortages occurred when pipelines could not secure enough interstate supply at regulated prices and curtailed deliveries in several interstate markets. The *intrastate* markets in Texas and Louisiana where gas prices were not regulated continued to have sufficient supply.

³ In the interim, the gas market went on a roller coaster ride of high prices in the early 1980s, encouraged by NGPA’s high ceiling prices for new production; this led to a contraction in the market exacerbated by

The 1980s saw other trends affecting the industry. The most important was the simultaneous emergence of an unregulated spot market after 1985 and the growth of independent gas marketers in the spot market. In this new, unregulated spot market, customers could buy gas from producers and the newly emerging marketers at prices significantly lower than regulated pipeline supplies. The pressure from LDCs and end use customers to access this market led FERC to promulgate Orders 380 and 436 (see Exhibit 1), aimed at promoting pipeline transportation services. With their customers turning to the spot market, pipelines' merchant activities suffered since they were locked into long term take-or-pay contracts with producers at prices above the spot market. Order 636 was aimed in part to finally resolve the so called take-or-pay crisis.

A second important development in the gas industry was the inauguration in 1990 by the New York Mercantile Exchange (NYMEX) of the first gas futures contract, centered on Henry Hub in south Louisiana. Futures trading has had a dramatic impact on gas markets. Futures provide a mechanism for price discovery and risk management and increase the number of participants in the market.

Properly seen, FERC Order 636 was one of several developments that revolutionized the gas industry. The importance of the Order lies in how it aligned regulation to the evolving industry and established a framework for a workably competitive gas market.

Exhibit 1
Legislative and Regulatory Actions Leading to a Competitive Gas Market

Action	Significance
Natural Gas Policy Act (1978)	Passed in response to gas shortages, began price rationalization and deregulation. Led to excessive gas prices in the early 80's.
FERC Order 380 (1984)	Allowed LDC's to escape minimum bill obligations to their pipelines, which provided the opportunity to acquire spot market gas; exacerbated pipelines' take or pay problems.
FERC Orders 436/500 (1985-1987)	Initial attempt at forcing pipelines to provide transportation services and to resolve take or pay problems.
Natural Gas Wellhead Decontrol Act (1989)	Fully decontrolled wellhead gas prices as of January 1, 1993.
FERC Order 636 (1992)	Restructured gas industry.

the 1982 recession, and a long period of gas supply excess and low prices from which the industry is only now recovering.

B. Order 636

FERC Order 636 made a number of technical changes to the regulation of interstate pipelines under the Natural Gas Act. These are summarized in Exhibit 2. In the main, Order 636 made three significant changes to the pipeline industry:

- Pipelines were forced to give up their merchant function and become solely transporters of gas. Transportation had to be on a non-discriminatory basis--open access--and unbundled from other pipeline services, principally storage.
- Pipeline rates were to be straight fixed variable rate (SFV) design with all fixed costs in the demand charge and only variable costs in the commodity charge. Rates could be discounted. This gave capacity holders clear price signals on the costs of transportation and related services.

Exhibit 2 Order 636 Changes

<ul style="list-style-type: none">• Interstate gas pipelines must provide open access transportation service that is “unbundled” from other services. Customers must be able to purchase gas storage, balancing services, and whatever sales service the pipeline continues to provide, separate from pipeline transportation. The transportation service provided must be equal for all customers.
<ul style="list-style-type: none">• Most interstate pipelines must provide “no notice” firm transportation service to customers who want it. This service allows the customer to call on a certain level of transportation capacity without the traditional nomination lead time. To provide this service the pipelines that had owned or contracted for storage service retained part of their storage capacity rather than offer all of the capacity as a separate unbundled service.
<ul style="list-style-type: none">• Interstate pipelines must provide firm shippers on downstream pipelines with access to capacity on upstream pipelines that the downstream pipeline has under contract. This is intended to prevent discriminatory blockage of use of the downstream pipeline capacity.
<ul style="list-style-type: none">• Firm shippers on interstate pipelines are allowed to offer reserved pipeline capacity that they do not need to other shippers. This capacity release mechanism requires posting the idle capacity on an electronic bulletin board and awarding the capacity to the highest bidder.
<ul style="list-style-type: none">• Firm shippers must be allowed to change their gas receipt points, allowing for multiple and changing sources of supply.
<ul style="list-style-type: none">• Interstate pipelines are allowed to charge market-based rates for their remaining sales service.
<ul style="list-style-type: none">• Generally, interstate pipeline transportation rates must use a straight fixed-variable rate design. This rate structure recovers a significant amount of pipeline costs through charges for the reservation of pipeline capacity (the fixed component), and the remainder of costs on the amount of gas actually flowed through the pipe (the variable component). Some flexibility is allowed to mitigate the detrimental financial effects that straight fixed-variable rates have on some customer classes.
<ul style="list-style-type: none">• Interstate pipeline tariff provisions must not interfere with the establishment of market centers and gas supply pooling areas.

- Capacity holders could resell unutilized capacity to other shippers, creating a secondary market in transportation capacity. The price of capacity was market determined, but could not exceed the pipelines' as-billed rate.

When these changes are combined with the growth of the spot market in gas, the development of the NYMEX gas futures contract, and the growth in the number of market players (see next section below), the results have been the emergence of a far more dynamic gas industry. In the next section, the paper addresses its structure and operations in the post-Order 636 environment.

C. General Structure and Operation of the Gas Industry Today

1. Production and Consumption

The size of the US gas market has varied over the years, but on average it consumes about 20 trillion cubic feet (Tcf) annually.⁴ The major gas producing regions of the US are shown in Exhibit 3. The largest producing market is the Gulf Coast, on shore and off shore Texas and Louisiana. Other major regions include West Texas, the Mid-Continent, and the Rockies. Coal production is found in the Appalachians and the Black Warrior (Alabama) gas producing regions. The Appalachians account for about 3 percent of total production, about 600 billion cubic feet (Bcf). Production from onshore Alabama, mainly the Black Warrior basin totals about 174 Bcf. The US imports about 10 percent of total consumption from Canada, mainly from Alberta. Small amounts of liquefied natural gas ("LNG") are imported from North Africa, mainly to provide peaking capacity in the Northeast in winter.

The largest gas consuming markets are located in the south and east as shown in Exhibit 4. Out of a total market of 19.7 Tcf in 1995, the West South Central, including the Texas/Louisiana petrochemical and power markets, accounted for 28 percent. The East North Central region, including Chicago and the Great Lakes market, was the second largest consuming region at 19 percent of the total. The Middle Atlantic region, including New York and Pennsylvania, was the third largest consuming area with 12 percent of the national total.

Exhibit 5 illustrates gas consumption by sector for the US Census regions east of the Mississippi (where 66 of the 79 mines the EPA has identified as candidates for methane recovery are located).

Exhibit 6 shows US gas consumption from 1970 through 1995 by consuming sector. In 1995 the industrial sector accounted for 44 percent of total gas consumed. Residential consumption was next in importance in 1995 at 25 percent. The electric utility and commercial uses followed at 16 and 15 percent, respectively.

⁴ Gas is measured in several ways. In terms of volume it is measured in cubic feet--Ccf (100 cubic feet); Mcf (thousand); Bcf (billion); Tcf (trillion). In terms of heat content it is measured in British thermal units (Btus) and therms (100,000 Btus). One Dth (decatherm or 10 therms) equals one million Btus (MMBtu). One Mcf equals about 1.03 MMBtu.

Exhibit 3 Major Natural Gas Basins

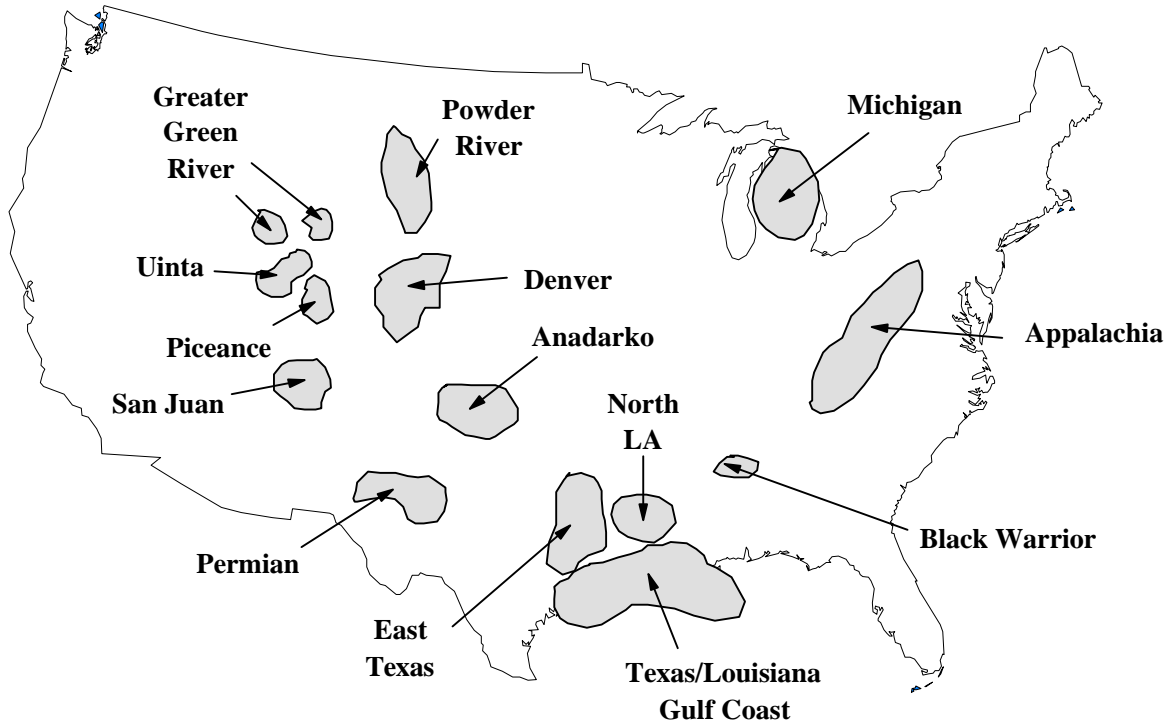
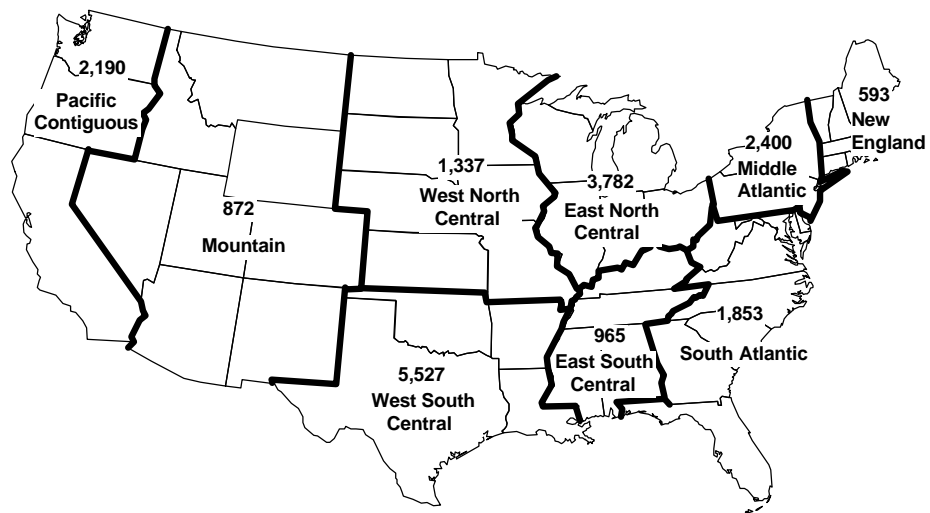
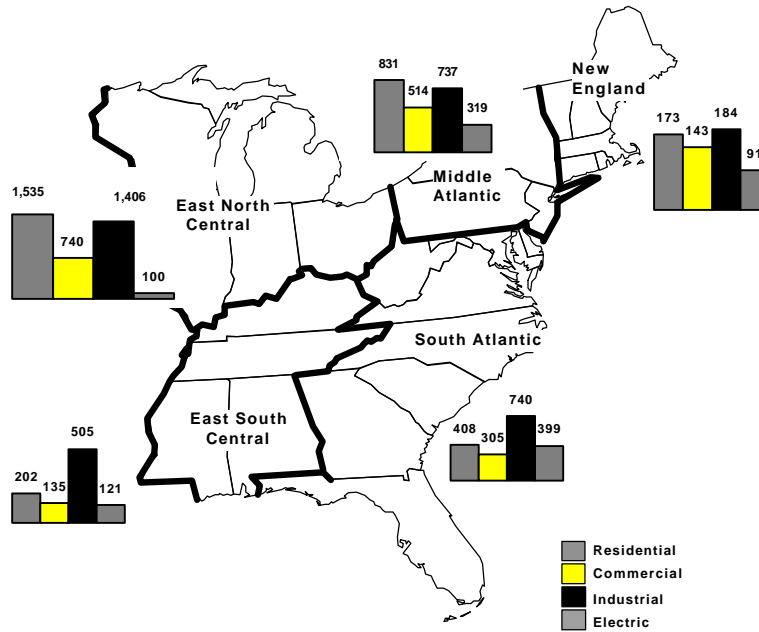


Exhibit 4 1995 US Gas Consumption by Census Region (Bcf)



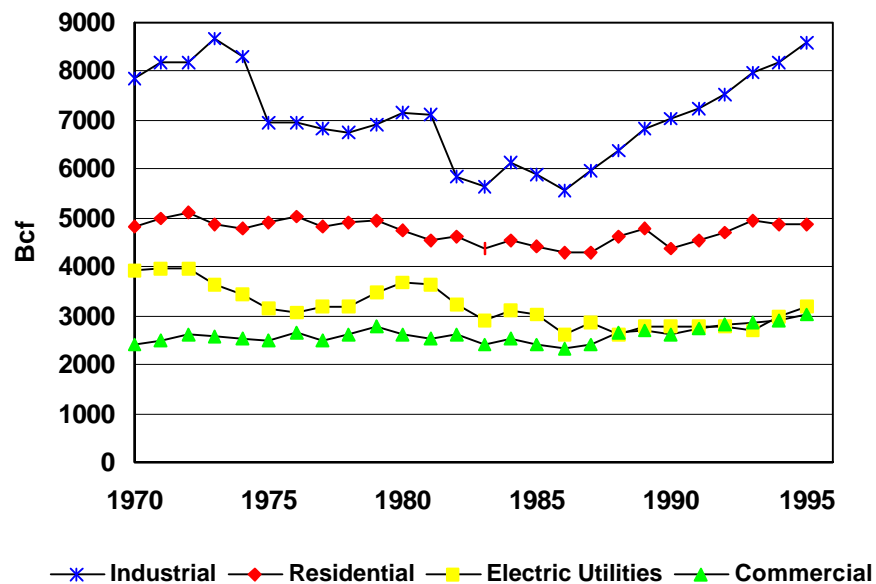
Source: U.S. Department of Energy, Energy Information Administration / Natural Gas Annual 1995

Exhibit 5 1995 US Gas Consumption East of the Mississippi



Source: U.S. Department of Energy, Energy Information Administration / Natural Gas Annual 1995

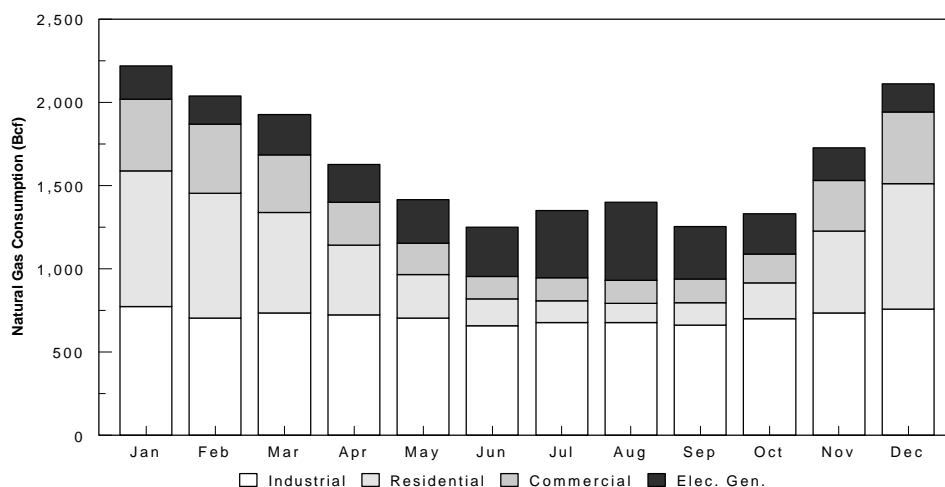
Exhibit 6 US Natural Gas Consumption by Sector



Industrial consumption is heavily influenced by economic conditions and the prices of competing fuels. Similarly, the electric generation market is highly dependent on power demand and alternative fuel pricing. Firms in these sectors are more likely to purchase gas from marketers and producers than from LDCs. Residential and commercial demand is highly seasonal and almost entirely served by LDCs. The typical residence consumes 125 Mcf per year; industrial and electric power plants can consume tens of thousands of Mcf per day.

One of the major characteristics of the gas market is the seasonality of consumption, due to the fact that gas is used substantially as a heating fuel. Exhibit 7 illustrates the seasonal nature of demand by end user sector. Note the winter peaking usage characteristic of residential and commercial demand and the “counter seasonality” of industrial and electric utility demand.

Exhibit 7
Seasonal Gas Demand by Sector
(1995)



Source: DOE-EIA Natural Gas Monthly, March 1996

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This suggests a major opportunity for gassy coal mines located near market areas: the potential use of coal mines as sites for natural gas storage. The emerging gas market has created a premium for storage located near markets, as LDCs and end users search for ways to create stability of supply without signing long-term commitments to pipelines. Mines offer another advantage. Because they are simply large underground spaces, they hold the potential for high injection and deliverability rates, which is also an advantage in today's market. It means that customers can have quick turnaround during periods of high demand. The Leyden coal mine in Jefferson County, Colorado (operated by Public Service of Colorado) has a total working gas capacity of 3 Bcf, but can accept high rates like 130 MMcfd of injection and, even higher, 185 MMcfd of peak withdrawal.

2. Major Players in the Industry Today--Who Does What

Gas is handled by a variety of players on its path from the well to the consumer. The players and their roles are described below.

Producers explore, drill and operate gas wells. There are thousands of gas producers in the US which draw from 284,000 wells (in addition to gas from oil wells). The average gas well produces 184 Mcf per day. The largest produce in the thousands of Mcf per day. In the Appalachian producing region, where most of the promising coalbed methane coal mines are located, the average well produces only 14 Mcf per day. The largest producers in the US include the major integrated oil companies--Exxon, Shell, Chevron, et. al. At the other end of the spectrum are the small producers, the "mom and pop" operators, often with a small number of wells.

Key Industry Players:

Producers--produce and sell gas

Gatherers--move gas to market

Processors--prepare gas for sale

Pipelines--long distance
transporters

Marketers--middleman merchants

LDCs--retailers

End users--consumers

In many cases the producer, or operator or the gas well, will not own the mineral rights to the gas in the ground. In these cases, the producer makes royalty payments to the owner. The typical royalty payment is one-eighth of the value of production. Thus, if the wellhead value is \$2.00 per MMBtu, the owner would receive about \$0.16 per MMBtu. The bulk of the price goes to the producer who bears the expense and risk of drilling and marketing the production.

Gathering pipelines collect gas from the wells and deliver it to processing plants. Large producers own their gathering systems. Other gathering systems are owned by independent operators or by pipeline affiliates (although in recent years most of these have been spun off as independent companies). The gathering pipeline rates are generally not regulated, unless the gathering system is part of an interstate pipeline or operates across state boundaries or offshore, which subjects it to FERC jurisdiction. For smaller producers, gathering charges can be significant where gatherers have local monopolies.

Processors take the gas from the field, remove impurities and, in some cases, strip out liquids (which are sold as natural gas liquids--NGLs--in a separate market) and prepare the gas to meet certain specifications required in the market. Natural gas is generally sold when it leaves the processing plant, or at the point it is delivered into the interstate pipeline grid. Producers should be aware that some volume of gas will be sacrificed in processing, and that an additional volume will be used as fuel in compressor stations (or simply lost) as it travels through the interstate pipeline system. Historically, the trip from the wellhead to the interstate delivery point has cost about 10 cents/Mcf.

The merchant function of the pre-Order 636 pipelines has been taken over by the **marketers**. Most gas today is sold through gas marketers, who aggregate supplies and "repackage" them with transportation and pricing terms for resale to LDCs or end-users. Marketers also provide services to producers that may include financing, hedging, gathering, processing or other related support activities. Most of the major producers act as their own marketers and may also market gas for others. Smaller producers usually sell gas to marketing companies since they do not have the resources to market their gas. Marketers will also provide an array of

similar services to their resale customers. Many pipelines and LDCs have marketing affiliates who act as independent marketing companies. There are hundreds of marketing companies of various sizes and specialties. The largest independent companies include Enron and Natural Gas Clearinghouse (NGC). Some marketers specialize geographically or work only with certain kinds of end users. The Eastern Group is a regional marketer active in the Appalachians.

Interstate pipelines provide transportation services under standard tariffs (general operating rules and rates kept on file at the FERC) and individual transportation agreements. The contract agreement to transport gas will be between the **shipper** and the pipeline. The shipper of a block of gas can be anyone in the chain of sale with a transportation agreement with the pipeline or pipeline capacity owner--the producer/production owner, the marketer, the LDC, or the gas end-user. (In most cases, producers are not the shippers of record; rather who they sell to will hold the transportation rights.)

The contract path is described in the transportation service agreement and names a receipt and a delivery point. The pipeline takes the gas from the receipt point, typically a numbered meter station/tap in the producing zone at the outlet of a gathering system or processing plant, and redelivers the gas to a delivery point, usually an LDC's citygate meter station. Some pipelines have delivery points at end user facilities where these are large industrial or electric power plants.

Besides transportation, pipelines also provide **storage** services or market hub services. (These are increasingly provided by independent operators as well.) Storage provides winter peak service and shorter term storage services (often referred to as "parking"). The latter allow shippers to match flows with market demand and to respond to price swings -- i.e., store when the market price falls and withdraw when the price rises. Most storage is in depleted gas fields and requires wells and compressors to inject the gas into the field. The rates of withdrawal depend on the permeability of the field. These fields are suitable for winter peaking storage. Mined caverns, usually salt domes, are used for short term storage and have the desired characteristic of quick injection and withdrawal. These storage services command a premium in the market.

Market hubs are places where several pipelines meet and where gas is transferred between pipelines. Major hubs include Henry Hub in Louisiana, Katy Hub near Houston, AECO-C in western Canada, Lebanon near Dayton, Ohio, and Leidy in Pennsylvania.

LDCs, being the primary retailers of natural gas, receive gas from the interstate pipelines through their citygates (LDCs may take deliveries through more than one citygate), step down the pressure, and redeliver or resell gas to customers on their distribution systems. LDC services for their distribution territories are provided under general rate and service schedules which are filed with the state public utilities commission. Virtually all LDCs provide transportation-only services to large end users. In several states, public utility commissions are considering programs to allow direct sales from marketers to residential and small commercial end users, with the LDC providing only transportation service.

3. Scope of Current Regulation

Economic, environmental and safety regulation of the gas industry is divided between a number of state and federal agencies. The regulations that affect gas transportation and sales are described below.

The basic regulatory structure remains the same under FERC Order 636. FERC still regulates interstate pipelines. Pipelines must have FERC certificates of public convenience and necessity in order to construct new facilities, and these certificates give pipelines the right of *eminent domain*. FERC no longer regulates producer prices or oversees production issues, but it still must approve any changes to pipeline rates and services. Pipelines' services and rates are described in the tariff which is kept on file at FERC in Washington, D.C. FERC also responds to requests for investigation of wrongdoing by interstate gas pipelines. Examples of problems that require investigation are allegations of discriminatory behavior with respect to transportation access, pricing, or rules that discriminate against classes of shippers and construction activities not in accordance with certificates. FERC can order pipelines to interconnect with shippers' facilities.

State public utility commissions regulate the rates and services of LDCs. Although regulations imposed on LDCs vary among the individual states, the types of jurisdiction are similar to those of FERC. Construction expenditures, tariffs, and customer complaints are regulated and resolved at the state level. Some state regulators are experimenting with incentive rate designs intended to reward both the LDC and its customers for cost savings.

A producer selling gas will encounter regulatory requirements when dealing with transporters, both pipelines and LDCs. For pipelines, this may involve FERC review of a pipeline's proposed addition of a receipt point if it involves new construction and any additional capacity needed (such as adding pipeline or new compression) to support a new source of supply. Pipeline transportation rates and LDC transportation services are subject to regulatory reviews by FERC and state commissions, but absent an ongoing rate case in which the shipper chooses to participate, there is little involvement with regulatory authority.

The major areas of future regulatory change are in the state regulation of LDCs. Several states are in the process of considering rules to allow small residential and commercial customers of LDCs to have the same level of access to interstate sales and transportation services as do the large industrial customers. In essence this would do to the LDCs what Order 636 has done to the pipelines.

D. Gas Prices and Gas Price Formation

The key to realizing opportunities from coal mine methane is understanding the dynamics of gas prices. This section focuses on interstate wholesale gas prices--that is the price of gas received by producers and paid by LDCs or large end users. Retail prices behind the citygate are noted to provide a more complete picture.

Natural gas prices are denominated in dollars per Mcf, MMBtu or Dth. (LDC rates are expressed in cents per therm.) Prices are quoted at major market hubs (where several pipelines converge); at LDC citygates, or at pipeline pooling points (the outlets of large processing plants or where a number of gathering systems deliver gas to a mainline pipeline).

The national marker price for gas is quoted at Henry Hub, Louisiana, where the NYMEX futures contract is traded. Recent prices have averaged about \$2.30 per MMBtu, but over the course of a year can swing from under \$2.00 to over \$5.00. The price of gas quoted at locations other than Henry Hub will differ from Henry Hub due to transportation differentials and local market conditions. Weekly gas journals, the internet, and traders provide spot market prices at most any market location on a daily basis. The Henry Hub spot price is listed daily in the *Wall Street Journal*, as are the various gas futures and options contracts.

As a general matter, gas prices in the spot market are determined for the following month during “bid week,” which is about a 10-day period when buyers and sellers make their deals before nominations for deliveries are due to the pipeline transportation managers. Bid week generally extends to the first day or two of the new month, as traders clean up details--that is, search for gas supplies for packages of gas that were supposed to be delivered. Weekly and daily prices (so-called aftermarket prices) diverge from the monthly bid week prices depending on supply and demand.

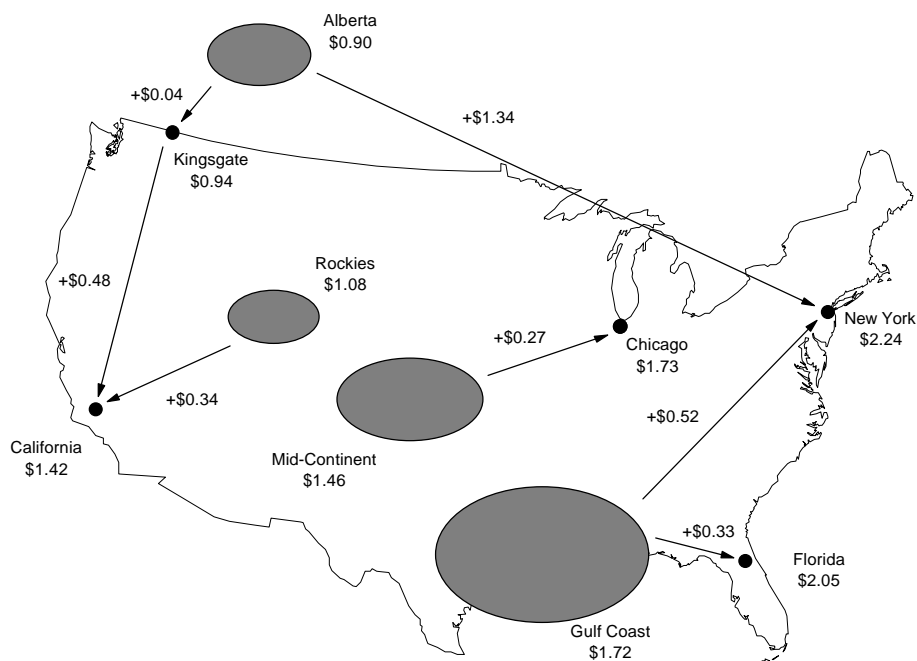
The fundamental aspect of the post-Order 636 market is that gas prices are formed in a largely transparent way by the forces of supply and demand; producers are price takers. Weather greatly influences demand for gas, since gas is used primarily as a heating fuel. The prices of competing fuels, like residual fuel oil, also influence demand for gas, but to a somewhat lesser extent. Supply is set by the available productive capacity and is subject to short term disruptions like hurricanes or freezing weather in the Gulf Coast.

The price received by the producer is referred to as the “netback” or what is left after all transportation and related charges have been netted out. Prices in the different producing markets are related to each other by the transportation differentials between producing and consuming markets. This is illustrated as follows and in Exhibit 8:

- The marginal producer in the Gulf Coast sells gas for around \$1.75 per MMBtu. Delivery to the New York market costs about \$0.50 per MMBtu, yielding a price at the New York citygate of \$2.25. This sets the market price in New York.
- A Canadian producer selling into New York must meet this price, but his transportation costs are \$1.35 from Alberta, yielding a netback from New York of only \$0.90. If the Canadian producer could find another market with higher netbacks, he would sell his gas to those markets. (As in fact many do in diverting Canadian gas to California and Chicago.)⁵
- At the same time, an Appalachian producer who is closer to the New York market faces a transportation cost of \$0.35 per MMBtu, and can realize a netback price of \$1.90 per MMBtu.

⁵ Recent pricing patterns in fact suggest that Alberta production is setting the price in the Chicago market, since the delivered cost of gas to Chicago is lower than the cost in the Gulf Coast plus normal transportation rates. This means Gulf Coast producers will direct their gas to the east coast until those lines are filled.

Exhibit 8 1995 National Gas Prices and Netbacks



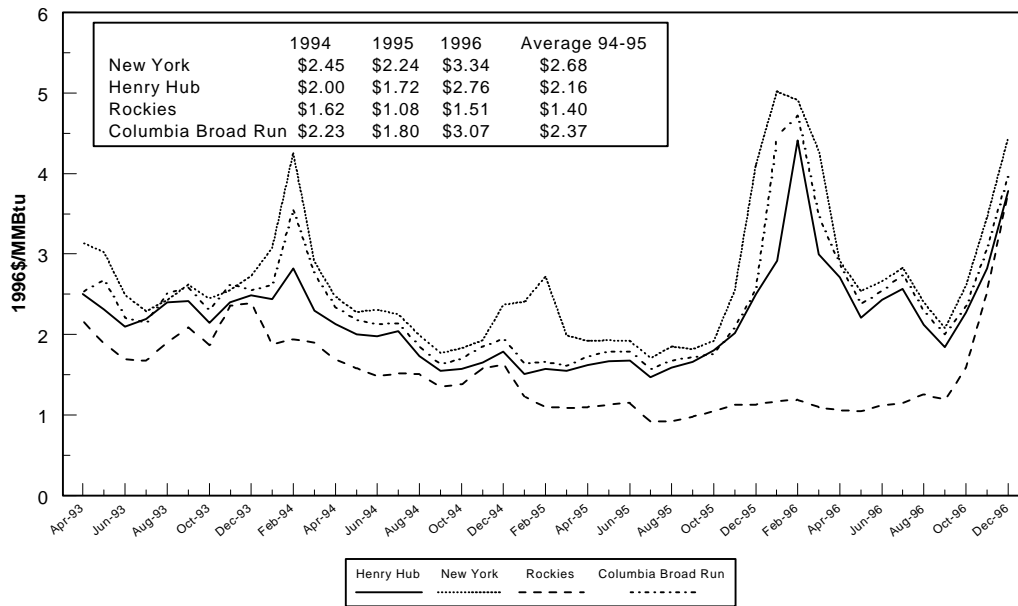
Note: All prices are in \$/MMBtu;
Supply area prices are delivered-to-pipeline; market area prices are citygate
Source: *Natural Gas Week, Natural Gas Daily*

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The result of netbacking on regional prices is illustrated in Exhibit 9. Gas delivered in the Appalachian region--signified by the Columbia Broad Run price--commands a premium over Henry Hub by the transportation differential between those two points. For the same reason, the New York citygate price is higher than Broad Run. (Rockies prices have been significantly lower due to the lack of transportation access out of the region and soft California demand.) Exhibit 9 also illustrates the annual volatility in gas prices and underlying seasonality in prices.

Finally, retail gas prices charged by LDCs are the sum of the wholesale price and the transportation and distribution margins allowed by state regulators as illustrated in Exhibit 10. As shown, residential customers have paid the most for gas and the large, frequently dual fueled, customers have paid the least. Exhibit 11 shows gas prices in the residential, commercial, industrial and electric utility sectors for the US Census regions east of the Mississippi.

Exhibit 9 Regional Gas Prices



Source: Natural Gas Week

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Exhibit 10 US Historical Gas Prices by Sector

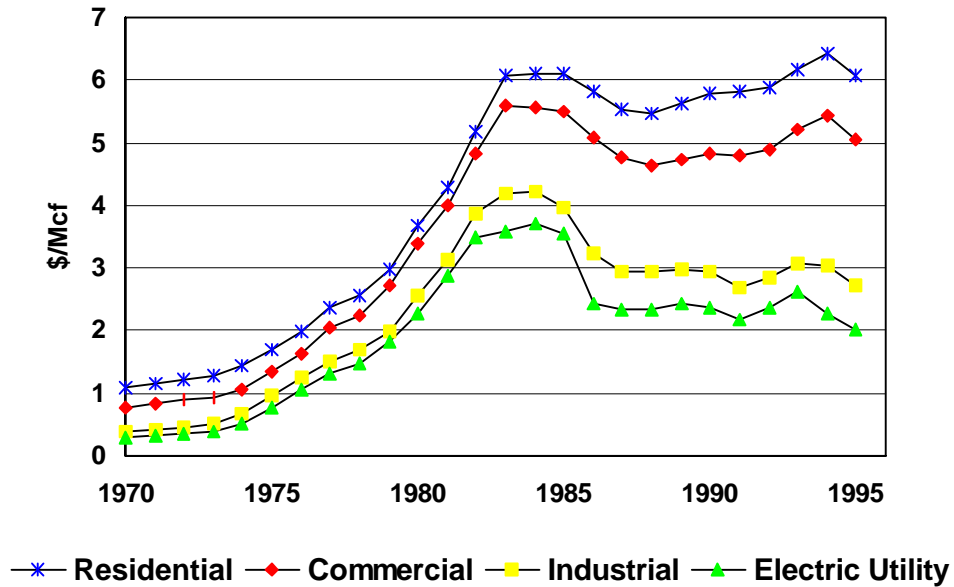
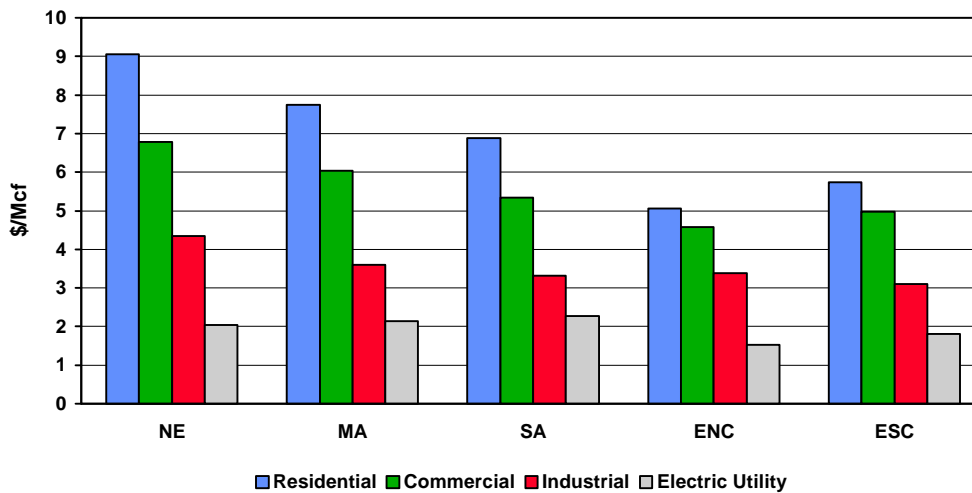


Exhibit 11
Gas Prices by Sector for Regions East of the Mississippi, 1995



E. Implications for Coal Mine Methane

Order 636 and other changes in the gas industry suggest the following for coal mine methane producers:

- Producers have a wide array of potential markets and opportunities to sell gas. Most gassy coal mines are near major gas consuming regions and markets. Mine operators can sell gas through marketers or directly to LDCs or end users in these markets.
- In today's gas market, coal mine methane producers have a greater opportunity to tailor gas sales deals to meet their needs and operating characteristics.
- Transportation access should not be a barrier to reaching markets with the secondary market in capacity and general open access rules. The cost of making physical interconnections and other related pipeline capacity additions will be a factor in individual situations.
- Producers of coal mine methane should be generally well positioned to receive higher netbacks than producers more distant from high value consuming markets. Individual situations may vary with local gathering and pipeline capacity conditions.
- The seasonal demand for gas, the pricing patterns of gas, and the high cost of pipeline capacity (see the next section) highlight the value of storage in the gas market. Using abandoned coal mines for storage would provide a market for coal mine methane and a valuable service in the gas market.

The next section describes the elements of typical gas sales and transportation contract agreements.

III. HOW NATURAL GAS IS MARKETING TODAY

Order 636 has fostered creativity in deal making by increasing the variety of gas sales and transportation arrangements. This section addresses key elements of the gas sales process.

The entire gas sales path--from wellhead to end user--involves one or more sales contracts and one or more transportation agreements. The market forces of supply and demand set the overall price level. The prices that individual producers realize will vary from the overall price level depending on terms of the sales contract, location relative to the supply and consuming markets, and transportation agreement terms.

A. Elements of Gas Sales Contracts

Gas sales contracts occur between any two parties for any period of time. The parties can include producer/marketer, producer/LDC, producer/end user or marketer/LDC and marketer/end user. (With today's active futures and derivatives market, one can also buy gas from several of the major banking and commodity organizations, that is, a Morgan Stanley or Bankers Trust can sell gas.) Gas sales contracts have certain standard contract terms that define how the sale will be executed:

- **Quantity.** The quantity of gas sold is expressed in two ways: daily volume and total contract volume. Total contract volume is equal to the daily volume multiplied by the number of days in the contract. The daily volume is expressed as a maximum daily quantity (MDQ), usually denominated in million Btus per day (MMBtu/d).
- **Minimum purchase obligation.** This is the minimum amount of gas that a buyer must take over the term of the contract, expressed on a daily and annual basis. Since buyers' requirements may fluctuate, having the ability to reduce takes is desirable.
- **Term.** The term of a contract can be as short as a day or it can run for several years. The spot market for gas, described by the Henry Hub price, refers to sales of gas for one month or less. Intermediate term contracts are for periods of up to 18 months. Long term contracts of 18 months or longer are increasingly rare.
- **Delivery/take obligation.** The terms of the delivery can be firm or less than firm. A firm delivery obligation means that the supplier is obligated to deliver the MDQ over the term of the contract. Failure to do so will invoke penalties under the contract. Less than firm can mean "as available" or obligate the supplier to make "reasonable efforts" to meet the delivery obligation. Another permutation is that delivery will be guaranteed for all but 10 or 15 days over the year. The companion obligation on behalf of the buyer will be the obligation to take all gas delivered under the contract. Failure to do so can lead to penalties and relieve the supplier of any obligation to continue in the contract. Shippers need to have the terms spelled out. "Secondary Firm" capacity means that there are recall rights on the volumes. Only "Primary Firm" customers have rights to the gas at all times.

- **Delivery point.** The delivery point is the location where gas is delivered to the buyer. Delivery can be made to the point of interconnection between the pipeline and the gathering system, the outlet of a processing plant, a market hub, a city gate or any point in between. This is largely determined by the owner of the capacity on the pipeline. A producer will seldom hold capacity on a mainline pipeline all the way to market.
- **Force majeure.** These define the “acts of God” that relieve the parties of their obligations under the contract. These provisions sometimes also include “market-out” terms that will allow either party to exit the agreement if market conditions change dramatically.
- **Warranties.** These further define the level of obligation that the parties have to perform under the contract. A typical “soft” warranty is a “best efforts” obligation, which requires the parties to use best but not heroic efforts to assure performance--i.e., that the gas is delivered. For a producer, this may include an agreement to replace gas not delivered with other gas or other fuels. Some contracts will be warranted with the reserves themselves: if the supplier fails to perform, the buyer can take over the reserves. Corporate warranties put the producing corporation’s balance sheet behind the contract, which, depending on the quality of the corporate assets, can be the strongest warranty.

The price of gas will also be included in the contract and is typically expressed in reference to a commonly followed market price or as a formula. This is the area of greatest variety in contract terms. Some typical pricing provisions include the following:

- **Fixed price.** A short term contract--one month or less--will have a fixed price for a fixed quantity which will be related to the current spot market price of gas. Longer term contracts rarely have fixed prices over the entire term of the contract. Where fixed prices are offered in longer term arrangements, they usually are at a substantial premium to the market to cover the risks inherent in fixing prices.
- **Floating spot price.** Some contracts will allow the price to float with the market price of gas at a specific location as reported in the various industry weekly newsletters: *Natural Gas Intelligence*, *Gas Daily*, *Natural Gas Week*, and *Inside FERC’s Natural Gas Market Report*, for example. Often the price will be quoted as a discount or premium to a specific location reported price. For example, the price may be Henry Hub plus \$0.10/MMBtu or Henry Hub minus \$0.05/MMBtu. The premium or discount will be determined by a combination of transportation rate differentials between the point of delivery and reported market price location and by competitive pressures. These contracts will have an automatic monthly or weekly price redetermination. Usually two publications are cited in a gas contract to protect the parties in the event that one publication might fold.
- **Base price with escalator.** Often contracts will set the price for a base period and then the price will escalate thereafter monthly or annually by some escalation factor. This can be a fixed percent, but is more often a market index of gas prices such as the NYMEX futures on the last day of trading for each month’s contract, or an index based on the reported prices in one or more of the newsletters. Some contracts will

escalate with an economic indicator such as the Consumer Price Index or Producer Price Index or an index tied to a specific industrial production measure. Escalators can also be based on the price of other commodities such as oil, coal or electricity. In one contract the escalator was tied to the change in the price of orange juice.

- **Ceiling and floor prices.** Longer term contracts may have provisions limiting the range of escalation. Thus the contract may have a ceiling which limits the upside of the contract. Producers may require higher base prices for such contracts. Similarly, contracts may have a floor to protect the downside. Collars refer to contracts that limit the range of escalation on the upside and downside.
- **Two part prices.** These prices will include a fixed price component and a floating price component. The fixed price acts as a reservation charge and may be expressed as either a fixed amount or some multiple of the MDQ payable monthly regardless of how much gas is taken. The floating price may resemble the spot market price of gas. Such contracts are available where the buyer needs flexibility in the amount of gas taken over the term of the contract and are more common in longer term contracts.

While basic gas prices received by sellers are the netbacks discussed in the earlier section, the terms of the sales contract will influence the final price that the seller receives. The price of gas will be higher with stronger delivery obligations (firm supply, strong warranties) on the part of the seller; with lower minimum take levels (allowing the buyer to swing on the seller's supply); with a longer term; with lower price escalation; and with more value-added service (see below). The price of gas will be lower with weaker delivery obligations; with higher minimum takes; with market-based pricing; with shorter term, and with pure commodity sales.

The value-added aspect of gas sales comes with tailoring a gas supply to the needs of an individual customer. This can include anything that prices the gas in terms other than pure spot market--such as tying it to the price of the buyer's product (e.g. orange juice or electricity). It can also include pairing firm delivery obligations with giving a buyer greater flexibility in daily takes. Value added service can include special billing and gas accounting services.

Such value added services are beyond the capabilities of most small producers, mainly because doing so involves greater risk or is staff intensive. On the other hand, these are the services that marketers provide. For these services, marketers will receive a markup on the base gas price. This markup varies with the level of service and how the marketer bundles his gas. For a straight sale of the commodity, the markup may be \$0.02 to \$0.05 per MMBtu. When a marketer can bundle the gas with a transportation contract, backed up by storage that would give him the ability to deliver the gas during the winter peak when supply and transportation is tight, the margin can be enormous--\$1.00 or more per MMBtu over what the producer receives. However, to receive such returns, marketers frequently take significant risks. These risks are managed by the application of portfolio strategies (balancing risks across a variety of suppliers and customers) and active hedging in the financial derivatives markets.

Use of financial derivatives has expanded greatly in the last five years with the increase in gas price volatility. The principal derivatives used in gas markets are futures contracts and options on futures. These are publicly traded and quoted daily in major newspapers. (The standard

contract is for 10,000 MMBtu per day delivered at Henry Hub for one month.) Producers can use these instruments to fix forward prices and reduce their risk. Indeed, many gas supply contracts today have prices floating at the monthly closing NYMEX contracts or some near equivalent spot market index. Producers will then use derivatives to “shape” the final price they receive in order to match their own risk preferences. Other derivatives instruments include over-the-counter swaps, offered by financial institutions and commodities traders. Swaps allow parties to a contract to exchange cash flows with a third party in order to lower risk.

B. Elements of Gas Transportation Agreements

The fundamental objective of Order 636 was to provide open access transportation to all potential shippers on a non-discriminatory basis and to allow a secondary market in unutilized pipeline capacity to develop. As a consequence, pipeline transportation capacity can be acquired directly from a pipeline or indirectly in the secondary market through the “capacity release” mechanism.

1. Direct Transportation Service

Entering into a long term capacity contract with an interstate pipeline is a substantial financial commitment with ongoing operational obligations. On some new pipelines constructed in the West, producers hold the long term contracts; however, most of the capacity on interstate pipelines is in fact controlled by LDCs with long term contracts. It is rare for a small producer to own pipeline capacity because of the cost. Transportation agreements will have the following key elements:

- **Capacity.** Expressed as MDQ and denominated in MMBtus or Mcf per day.
- **Receipt and delivery points.** These define the endpoints of a capacity holder's ownership of capacity: the receipt point (where the transportation begins) and one or more citygate delivery points where the pipeline's obligation ends. Capacity holders have firm rights to the capacity between these points, as well as firm rights through the receipt and delivery points themselves. (These points are a shippers *primary* receipt and delivery points. Shippers can use alternative or *secondary* receipt or delivery points, but they will not have first priority of shipment there.)
- **Rates.** The transportation agreement will refer to the tariff on file at FERC for rates. These are two part, demand/commodity rates. The monthly demand charge recovers the cost of the capacity and is multiplied by the MDQ. This is a fixed monthly cost regardless of the amount of gas that is shipped. The commodity charge covers the variable costs of transportation, usually a few cents per MMBtu plus the fuel charge, which is taken in kind and is expressed as a percent of throughput. Many long distance pipelines have either zoned rates or mileage based rates, where the total cost depends on distance. Some pipelines that resemble web systems will have postage stamp rates, one price for shipment anywhere on the system, regardless of distance. The major pipelines serving the Appalachian region--Columbia Gas Transmission (Columbia) and Consolidated Natural Gas (CNG) are the latter. Their rates are as follows:

Columbia FTS: Demand = \$8.80/MMBtu/mo; Commodity = \$0.0267/MMBtu; Fuel = 2.41%

CNG FT: Demand = \$5.72/MMBtu/mo; Commodity = \$0.0371/MMBtu; Fuel = 2.0%

- **Operational rules.** The transportation agreement will again refer to the tariff for operational rules. These cover nominating procedures (each month and each day, shippers must inform the pipeline of how much gas they propose to transport); scheduling (daily flow rates); overrun penalties (for taking too much gas from the pipeline); balancing penalties (shippers are required to balance receipts with deliveries daily and monthly). The pipeline agreement will also cite shippers' obligations when the pipeline issues Operational Flow Orders (OFOs).
- **Special provisions.** Occasionally, a shipper will request special services from a pipeline that protect the shipper from incurring onerous penalties described above. This can include an Operational Balancing Agreement that allows the pipeline to resolve imbalances among multiple shippers. In addition, the agreement may also cover the construction of a new interconnection between a gathering line and the pipeline, or a new delivery interconnect. In these cases the cost of the new facilities will either be paid in advance by the shipper or through a rate adder.

In evaluating the cost of transportation, a shipper takes into account the large fixed costs associated with contracting for firm transportation capacity. For example, the fixed charges for 10,000 MMBtu per day of firm transportation capacity on Columbia and CNG would run \$88,000 and \$57,200 respectively *per month*, which equates to \$1,056,000 and \$686,000 *per year*. Thus it is clear that in order to justify this kind of expenditure, a shipper has an incentive to use the capacity at a high load factor--that is to fill it up all the time.

Exhibit 12 presents the load factor calculations for Columbia's FTS service and CNG's FT service.⁶ The 100 percent load factor assumes the capacity is fully employed; while the 70 percent load factor calculation presents the cost of firm capacity per MMBtu of throughput when the capacity is not used 30 percent of the time. Because of this cost structure, it is incumbent on the capacity holder to purchase the minimum capacity necessary. But since gas use is so seasonal, there is almost always excess capacity available outside the winter months. Hence, many shippers seek released capacity transportation service.

Exhibit 12
Pipeline Tariff Rates, \$/MMBtu

Pipeline	100% Load Factor Rate	70% Load Factor Rate
Columbia Gas Transmission	\$0.32 plus 2.41% fuel retention	\$0.44 plus 2.41% fuel retention
CNG Transmission	\$0.23 plus 2% fuel retention	\$0.31 plus 2% fuel retention

⁶ FTS refers to "Firm Transportation Service" while FT stands for "Firm Transportation" service.

2. Released Capacity

Because of the seasonal nature of gas demand and the inherent uncertainties of the market, and because pipeline capacity is expensive, capacity holders with excess capacity on hand release unused capacity to other parties to recover some of their fixed costs. The original capacity holder remains liable for the demand charges due the pipeline. In addition, all of the same pipeline tariff terms and operating rules apply to the secondary shipper over the term of the contract with the primary shipper.

Released capacity is usually sold for a specific period of time which can be daily, monthly or longer. Often released capacity will have a “call back” provision, that allows the capacity owner to take back the capacity for a period of time when demand is high. As such, released capacity that is subject to call-back may not be described as firm transportation service and anyone shipping under such released capacity may be subject to interruptions. However, where the released capacity agreement has no callback provision, it is as reliable as any direct purchased capacity from the pipeline.

The cost of released capacity is expressed as a one-part rate that recovers for the primary shipper some portion of his demand charges and all of the variable costs. Under FERC rules, the price of released capacity is capped at the pipeline’s underlying transportation rate expressed at the 100 percent load factor. Seldom do primary shippers recover their full costs of capacity, since by its definition such capacity is surplus. In addition, service that is subject to recall rights is less firm and thus less valuable. February released capacity on Columbia and CNG have gone for \$0.23 and \$0.18 respectively. Last July, Columbia capacity was trading around \$0.028 per MMBtu and CNG for \$0.0153 per MMBtu. Compare these rates with the 100 percent load factor in Exhibit 12. As is shown, the rates are much lower.

There are two ways to acquire released capacity: by pre-arrangement with the capacity holder and via bidding on the pipeline’s electronic bulletin board (EBB). A shipper may make a deal directly with a capacity holder. If the agreed price is below the maximum rate, the terms of the deal must be put on the EBB where it is subject to bidding from other shippers. If none offer the same price and terms, then the release is consummated. Alternatively, some primary capacity holders post available capacity on the EBBs which others can acquire at the posted prices.

One aspect of released capacity should be noted. Capacity holders can only release capacity between their contracted primary receipt and delivery points. Replacement shippers who wish to receive and deliver gas at these primary receipt and delivery points will have the functional equivalent of firm service. However, most use intermediate points of receipt and delivery. As such their receipt and delivery points will not have the same degree of firmness, since other primary users may use these points. This is a consideration when selling gas using released capacity or selling gas to someone who is using released capacity.

3. Operational Issues

The day to day business of transporting gas can be complicated and involved. A significant aspect of meeting contract obligations requires attention to the details of delivery. Many producers and all marketers have large transportation/exchange departments to manage daily

business of moving gas and tracking the gas accounts. This is part of the value added service they provide customers. The major operational issues are the gas quality requirements, nominating and scheduling, balancing, and managing under occasional operational flow orders. These are addressed below.

a. Gas Quality

Natural gas must have certain physical characteristics before gas pipelines and LDCs will accept the gas into their systems. These conditions are designed to prevent an increment of gas from contaminating the system supply. These requirements are described in the General Terms and Conditions portion of the pipeline tariff. Gas supply contracts require the producer to meet the quality requirements. The quality specification for CNG and Columbia are shown in Exhibit 13.

**Exhibit 13
Examples of Gas Quality Specifications**

Specification	Columbia Gas Transmission	CNG Transmission
Hydrogen sulfide content	0.25 grain max per 100 cubic ft.	0.25 grain max per 100 cubic ft.
Sulfur content	20 grains per 100 cubic ft.	20 grains per 100 cubic ft.
Particulates content	Must be commercially free of particulates	Must be free of dust, gums, dirt, and objectionable odors
Carbon dioxide content	Not specified	Max. 3 percent by volume
Nitrogen content	Not specified	Max. 3 percent by volume
Oxygen content	Not specified	Max. 0.2 percent by volume
Heating value	Min. of 969 Btu per cubic ft.	Within range of 967 to 1100 Btu per cubic ft.

The gas industry standard water content is 7 lbs. per Mmcf. Methane from unmined coal seams frequently meets these requirements or can be made to with minimal processing (dehydration is the most common). On the other hand, typical gob gas composition includes the following elements:

Oxygen	between 2 and 8 percent
Nitrogen	between 9 and 26 percent
Carbon dioxide	between 3 and 9 percent
Water vapor	saturated

Gob gas will require in most cases more processing to prepare it for market.

b. Nominations and Scheduling

Pipelines operate on a monthly and daily cycle for scheduling the flow of gas volumes through the pipeline system. Approximately one week before the start of the month shippers must submit their nominations for how much gas they plan to flow on a daily basis for that month, expressed as MMBtu or Mcf per day. The nominations must indicate the receipt point and delivery points for the gas being shipped. Pipelines then schedule the flows and indicate priorities of delivery. Any shipper with firm capacity will have the top priority. Other shippers will be scheduled behind the firm shippers, assuming capacity is available. Shippers are required to submit gas at roughly equal rates throughout the day.

Daily nominations are also required throughout the month. Usually by 10 AM each day, shippers are required to notify the pipeline of expected deliveries for the next day. Daily nominations allow the pipeline and shippers to adjust throughput to account for variability in demand. Many pipelines allow intra-day nominations for the same reason.

c. Balancing

Pipelines require that shippers' receipts equal their deliveries of gas. Due to the variability of demand and supply over the course of a month, receipts and deliveries can get out of balance, which can have ripple effects throughout the system and cause operational problems. To prevent these imbalances from becoming unmanageable, the pipelines have instituted tariff rules that limit the size of supply/delivery imbalances that are allowed. Tolerances of five to ten percent are typically allowed without penalty. Some pipelines apply penalties to daily imbalances and others allow daily imbalances to be summed over a period of a month, allowing corrections to be made during the month to avoid a monthly net imbalance. Cash settlements are made monthly on imbalances for both the price of the gas and any penalty charges. If the shipper has a positive imbalance, the pipeline will pay a discounted price for the positive imbalance volume. If the shipper has a negative imbalance, the pipeline will charge the shipper a premium price for the imbalance volume. Shippers can use scheduling to control monthly imbalances. For example, daily overages early in a month can be counteracted by nominating underages in subsequent days.

d. Operational flow orders

Pipelines use operational flow orders (OFO) to maintain gas flows as best they can in emergency situations. Given several hours notice, a pipeline can order shippers to inject and withdraw specified volumes of gas at specified receipt and delivery points on the pipeline. OFO's are not to be used as a routine daily tool to manage gas flows.

OFOs can adversely affect a producer's ability to meet contract obligations. In such cases, the shipper may turn to other supplies or use special operational balancing agreements with the pipeline to maintain deliveries.

C. Creating Value with Contract Terms

As the first section of this paper points out, coal mine operators, like any gas producer, will be price takers for the methane they produce, because market forces determine the underlying

price of gas. Producers, however, can receive above (or below) market prices depending on the specifics of the particular supply arrangements they enter into. The price received for gas will be determined by the value of the gas in the particular market where it is sold (geographic and sectoral), by the value that the specific sales terms create, and by the additional services the seller provides.

1. High Value Markets

Value is added in several ways. The first has been mentioned in the previous description of netback pricing: location can “create” value for the producer fortunate enough to be located near consuming markets that are also a considerable distance from other gas supplies. The northeast is an example.

Similarly, there are high value market sectors. Specific kinds of customers will have a higher value than others. Customers that use higher cost alternatives to gas (e.g., low sulfur residual fuel oil, distillate fuel, propane, electricity) will value gas more than those who can use lower cost alternatives (high sulfur residual fuel oil, coal). This points to certain industrial and electric generating uses as well as to residential and commercial users. Historically, the latter have been restricted to purchasing gas from LDCs.

Some states are experimenting with unbundling the services that LDCs provide to their customers, similar in concept to what Order 636 did with interstate pipeline services. This includes New York and Vermont in the northeast and Maryland in the mid-Atlantic. Such unbundling will open up new high value, profitable markets to producers and marketers. A number of aggressive marketers are positioning themselves for this market, with the intent of becoming national brand name providers of natural gas.

The costs of reaching high value markets are high. While selling to LDCs may only require responding to requests for proposals or some minimal marketing effort (including, however, establishing credit worthiness as a prerequisite) reaching end users can be a substantial undertaking. Aiming towards these markets will involve substantial sales and contract management efforts. More important, however, is the necessary investment in pipeline capacity, storage and other delivery mechanisms that involve substantial costs in financial and personnel resources.

2. Tailoring Contract Terms

Another way many producers and marketers distinguish their gas product is by developing contract terms that create additional value for the buyer. These terms can include the following:

- **Pricing.** Sellers can create a higher value gas supply by tailoring the pricing terms to the needs of the customers. This can include providing fixed prices for a period or matching the price movement to the product value of the customer (as is done with some electric power plants where the price of gas will be tied to the price of electricity in the power pool in order to guarantee the customer's power plant will be dispatched). Such arrangements create value by shifting risk to the producer.

Where the producer can tolerate this risk, this can yield higher prices and higher returns. Marketers are especially well equipped to manage these risks.

- **Delivery/take variability.** Buyers will pay a premium for the right to vary the level of takes from a supplier. Some suppliers, therefore, offer “swing” contracts that impose no minimum take obligations on buyers. Again, this places the supplier at risk since he must lay off the gas not taken to other buyers. In the alternative, the supplier may have a storage contract that allows him to divert untaken gas to storage for withdrawal later.
- **Firm supply/price.** Some buyers may value a firm gas supply at a known price. That is, the buyer knows the gas will always be there at either a previously arranged price or at a widely known market price, such as the spot price for a specific locale.
- **Long term supply.** Guaranteed supply for a long term can provide additional value in that it provides some supply certainty and lower transaction costs.

As noted in several instances above, most of these contract terms for adding value require the supplier/producer to take on additional risk--either market risk or commodity risk. The financial markets provide more or less effective ways to manage these risks--at a cost. Marketers manage these risks by using portfolio techniques to balance their obligations and exposures, in addition to making widespread use of derivatives. Finally, to be able to provide some of the delivery guarantees, suppliers have to have other physical and contractual assets in pipeline or storage capacity to effect these contract terms.

3. Value-added from Bundling Gas with Other Services

Pipelines prior to Order 636 were able to reap monopoly profits by bundling gas with delivery services. Order 636 directed pipelines to unbundle their services to allow buyers to purchase separately only those services they wanted. Marketers and others have been able to generate greater profits by rebundling gas with delivery services particularly with storage and firm pipeline capacity.⁷ A producer or supplier who controls pipeline or storage capacity during the winter peak in New York, for example, will be able to realize a significantly higher price than in the Gulf Coast. The value in this instance is the gas-cum-delivery capability. Suppliers can provide several kinds of bundled services, all of which require the ability to get gas to a market that is in short supply because of delivery bottlenecks.

- **Peak or winter service.** A supplier will provide firm gas delivery during the peak demand period, requiring the supplier to have delivery capabilities.
- **Balancing services.** A supplier will take over gas balancing obligations and will provide volumes necessary to meet imbalance corrections.
- **Management services.** A supplier will provide all gas accounting, billing and other “back-room” services.

⁷ Bundling by marketers is not necessarily monopolistic since there are many marketers competing on generally the same footing as opposed to a single pipeline serving a given market.

- Btu service. A supplier will guarantee that the buyer receives the necessary Btus to meet his equipment needs. This may involve providing gas, coal, oil, or propane interchangeably, on short notice.
- Back-up or stand-by services. The supplier will be the provider of last resort to guarantee deliveries where guarantees are needed.
- Financial services, price guarantees. Increasingly, the large suppliers provide financial hedging services to customers. This will include executing and managing futures and options positions or providing price/commodity swaps. Such risk management is becoming an increasingly valuable capability.
- Creative bundling. There have been some very creative deals in recent years. One marketer sold gas bundled with SO₂ trading allowances.

In short, bundling requires a range of capabilities and assets. These are most often held by marketers and the larger producers.

IV. STRATEGIES FOR COAL MINE METHANE

This paper has described in broad terms how the natural gas market operates. Today's gas market is largely a result of the regulatory changes that have occurred under FERC Order 636. From the standpoint of the gas producer--whether from a coal bed or more conventional settings--this has resulted in market-based pricing, a greater access to the market, and wider opportunities to market gas to secure the highest value for production, including through the use of risk management tools.

The advantage that a coal mine operator can have relative to conventional gas producers is that drilling and related methane drainage costs may have to be borne in many cases. With the cost of gas wells being sunk costs, the profitability of marketing the methane will depend on the price received relative to the incremental costs of preparing the gas for market.

Coal bed methane production in advance of mining can also improve mining profitability. It has been shown that methane drainage prior to mining improves mine productivity. Reducing methane content in the coal seam minimizes gas seepage into the mine that would require suspension of mining operations until the gas was vented. Producing the coal bed methane reduces gas outs and improves overall mine productivity. A developer can market the enhanced productivity benefits to the mine.

The prices producers of coal mine methane will receive will depend on the quality and reliability of the gas produced, the location of the gas relative to competing supplies, and the extent to which the mine operator can create value through the addition of related services and bundling. Thus four broad options are available to producers from coal mines:

- Partner with a gas producer to develop and market the methane from a coal mine in exchange for royalty payments. Because coal mine operators are not in the gas business, in most cases they will find it advantageous to allow a gas producer to develop the methane potential and take the marketing risk. The mine owner would receive a royalty for all gas developed and sold. Typical royalties for gas production are one-eighth of the wellhead value of the gas (after all gathering, processing costs have been subtracted from the sales price). Some coal mine operators receive between three-sixteenths to one-quarter royalties. The higher royalties may be due to the fact that in some cases, wells for methane production are already in place. Higher royalty shares may be negotiated with greater participation by the mine operator. The major issues involved with such arrangements involve coordinating gas and coal production, safety issues, and mine management.
- With the contracting and pricing flexibility that is characteristic of the market today, mine operators may be in a better position to sell output consistent with their operational requirements. Thus, variability in gas production from coal mines may not preclude the marketability of the methane, although it may reduce the price to the mine operator.
- Actively produce and market methane as a commodity. Especially where a mine already has wells and gathering systems in place, it may be more advantageous to directly sell methane to aggregators (marketers or LDCs) rather than accept a royalty payment. The price that a coal mine methane producer would receive would

be the netback to the region of the coal mine gas production. For an Appalachian producer, this may mean the Columbia Appalachian price or the CNG South Point price. For mines further west, the price could be a Lebanon or Chicago price. (It is possible that the final price received would be a discount off the regional price to account for localized transportation.)

The cost of marketing gas in this way would be any costs associated with getting the gas into the transmission system, including gathering and the cost of interconnection. Interconnection costs are generally modest, depending on the pressure of the pipeline that must be tapped into. Hot taps (taps made into a line under pressure) typically cost a few thousand dollars for a low pressure (300 psi), small diameter system, to over \$100,000 for a large diameter high pressure system. This strategy assumes that the buyer would own the mainline transportation capacity.

Such a strategy would still allow a producer to develop special contract terms or use derivatives to hedge risk or create more pricing certainty. If the price received from this approach meets a producer's investment criteria, this would be the lowest cost, least risky approach.

- Acquire pipeline capacity to the market. This more aggressive strategy is suitable for larger producers and could be accomplished by acquiring capacity directly from the pipeline or indirectly through the secondary market. Having pipeline capacity can do two things: get the producers' gas to a market more accessible to many more buyers and provide a greater certainty of supply to buyers. Having the ability to deliver gas to a major hub would provide greater opportunities for sales at prevailing market prices. Having gas bundled with capacity, particularly nearer markets, will allow producers at times to capture higher prices. The major additional cost of this option is the cost of securing pipeline capacity. There will be additional marketing costs to manage the capacity and sales.
- Become more like a gas marketer. For larger producers of coal mine methane, acting as a gas marketer in providing a variety of services related to gas (and possibly coal) is another option. Several opportunities suggest themselves:
 - ⇒ Some coal mines may have special opportunities to provide a total Btu type service that would include the provision jointly of coal and gas. Such Btu deals involve more typically gas/oil/propane, since these fuels can be used interchangeably in some applications. Coal mine operators could provide joint coal and gas services in some cases to nearby power producers for use in both baseload and peaking units.
 - ⇒ Some gas marketers have acquired SO₂ allowances to bundle with gas supply to enhance the value of the gas. Similar strategies can be followed by coal bed methane operators, and expanded to include NO_x or greenhouse gas emissions reductions.
 - ⇒ Where coal mine methane production is well situated relative to markets (i.e., both in terms of proximity and pipeline capacity availability), the mine operator should be able to secure higher netbacks. As a general matter, Appalachian production should receive higher prices than gas produced in

the Gulf Coast or other gas producing areas. Typically, Appalachian production commands a \$0.20 per MMBtu premium over gas from the Gulf Coast. Higher netback prices for coal mine methane will enhance mine profitability. The prices that such production could command can be further enhanced through providing special delivery and contract terms.

- ⇒ High deliverability gas storage--storage that allows rapid injection and withdrawal--commands significant premiums in the market. Abandoned coal mines can be used for such storage development. The proximity of such storage to market areas would allow users of storage to receive higher seasonal gas prices. Coal mine methane production can be used to fill or provide some portion of the gas in storage.

While the opportunities of such arrangements for receiving higher returns would be greater, so too would the costs of developing a marketing organization and investing in the necessary infrastructure.

For any of these strategies, methane producers should employ creative contracting and pricing strategies. These may involve special pricing terms, delivery assurances, and the like.

The opportunities available to methane producers are far greater than in the past. The ultimate success of methane marketing ventures will depend on local conditions affecting the cost of getting gas to market and the prices that the methane can command.